BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF THE	**)**	
APPLICATION OF CHESAPEAKE	**)**	
UTILITIES CORPORATION FOR	**)**	
APPROVAL OF A CHANGE IN ITS GAS	**)**	**PSC DOCKET NO. 15-1362**
SALES SERVICE RATES (“GSR”) TO BE	**)**	
EFFECTIVE NOVEMBER 1, 2015 (FILED	**)**	
SEPTEMBER 1, 2015)	**)**	

DIRECT TESTIMONY OF

JEROME D. MIERZWA

ON BEHALF OF THE

STAFF OF THE DELAWARE PUBLIC SERVICE COMMISSION AND DIVISION OF THE PUBLIC ADVOCATE

January 27, 2016

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

CHESAPEAKE UTILITIES CORPORATION
DOCKET NO. 15-1362
DIRECT TESTIMONY OF JEROME D. MIERZWA

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I. <u>STATEMENT OF QUALIFICATIONS</u>

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Jerome D. Mierzwa. I am a Principal and Vice President of Exeter Associates, Inc. ("Exeter"). My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter specializes in providing public utility-related consulting services.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I graduated from Canisius College in Buffalo, New York in 1981 with a Bachelor of Science Degree in Marketing. In 1985, I received a Masters Degree in Business Administration with a concentration in finance, also from Canisius College. In July 1986, I joined National Fuel Gas Distribution Corporation ("NFG Distribution") as a Management Trainee in the Research and Statistical Services Department ("RSS"). I was promoted to Supervisor RSS in January 1987. While employed with NFG Distribution, I conducted various financial and statistical analyses related to the company's market research activity and state regulatory affairs. In April 1987, as part of a corporate reorganization, I was transferred to National Fuel Gas Supply Corporation's ("NFG Supply's") rate department where my responsibilities included utility cost of service and rate design analysis, expense and revenue requirement forecasting, and activities related to federal regulation. I was also responsible for preparing NFG Supply's Purchase Gas Adjustment ("PGA") filings and developing interstate pipeline and spot market supply gas price projections. These forecasts were utilized for internal planning purposes as well as in NFG Distribution's purchased gas cost review proceedings.

In April 1990, I accepted a position as a Utility Analyst with Exeter. In December 1992, I was promoted to Senior Regulatory Analyst. Effective April 1, 1996, I became a Principal of Exeter. Since joining Exeter, my assignments have included evaluating the gas purchasing practices and policies of natural gas utilities, utility class cost of service and rate design analysis, sales and rate forecasting, performance-based incentive regulation, revenue requirement analysis, the unbundling of utility services, and the evaluation of customer choice natural gas transportation programs.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS ON UTILITY RATES?

A. Yes. I have provided testimony on more than 200 occasions in proceedings before the Federal Energy Regulatory Commission ("FERC"), utility regulatory commissions in Georgia, Illinois, Indiana, Louisiana, Maine, Montana, Nevada, New Jersey, Ohio, Pennsylvania, Rhode Island, Texas, Utah, and Virginia, as well as before this Commission.

II. <u>SCOPE AND PURPOSE OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Exeter was retained by the Staff of the Public Service Commission ("Staff") and the Division of the Public Advocate ("DPA") to review the Gas Sales Service Rate ("GSR") application of Chesapeake Utilities Corporation ("Chesapeake" or "the Company") and evaluate the reasonableness of the Company's gas procurement practices and policies. The purpose of my testimony is to present findings and recommendations to the Commission concerning issues raised by the application and the Company's ongoing gas procurement policies and practices. Also testifying in this proceeding on behalf of Staff is Mr. Jason R. Smith. Mr. Smith summarizes the Company's application and proposed rates and also addresses prior GSR settlement agreements.

Q. IN PERFORMING YOUR REVIEW AND ANALYSIS, WHAT DATA SOURCES DID YOU UTILIZE?

A. I reviewed the Company's application, responses to discovery requests, and the Company's 2015 Long-Term Gas Supply and Demand Strategic Plan. I also reviewed information provided in other Company proceedings before the Commission.

Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, I prepared this testimony.

III. <u>SUMMARY OF CONCLUSIONS</u>

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A. My findings and recommendations are as follows:

- The Company has not correctly applied the procedures approved in Docket No. 13-383 for the recovery of excess upstream interstate pipeline capacity costs from firm sales and transportation customers. Correctly applying those procedures and updating the Company's calculation to reflect actual rather than estimated capacity release revenues results in an additional credit of $188,867 to firm sales customers;

- The Company should regularly evaluate the reasonableness of its current asset management arrangement ("AMA") fee by comparing that fee with the expected benefits that the Company's GSR customers would receive if the

Company retained and managed its upstream interstate pipeline capacity rather than assigning it to a third-party under an AMA;

- Staff/DPA should not oppose opening a discussion with Chesapeake regarding future AMA arrangements with an affiliate of the Company; and.
- Staff/DPA and the Company should hold quarterly discussions to review the Company's hedging program, under-and-over collection balances, and other areas of interest. This would include determining whether measures should be implemented in the Company's annual GSR application to reduce the volatility of GSR rates caused by the amortizations of gas cost over- and under-collections.

IV. <u>SETTLEMENT IN DOCKET NO. 13-383</u>

Q. BRIEFLY DESCRIBE CHESAPEAKE'S INTERSTATE PIPELINE TRANSPORTATION, OR DELIVERY, ARRANGEMENTS.

A. Chesapeake is directly interconnected with only one interstate pipeline – Eastern Shore Natural Gas ("ESNG"), a Chesapeake affiliate. Therefore, all of Chesapeake's gas supplies are physically delivered to the Company by ESNG. However, ESNG's facilities are not located in a natural gas production region and, therefore, Chesapeake reserves capacity on three interstate pipelines which are upstream of ESNG that deliver gas from production regions to ESNG. These three pipelines are Transcontinental Gas Pipe Line Corporation ("Transco"), Columbia Gas Transmission Corporation ("Columbia"), and Texas Eastern Transmission Company ("Tetco").

Q. HOW DOES A GAS UTILITY TYPICALLY DETERMINE THE AMOUNT OF PIPELINE CAPACITY THAT IT SHOULD RESERVE OR MAINTAIN?

A. A gas utility would typically reserve pipeline capacity sufficient to meet the design day demands of its firm retail sales customers. Design day is an extremely cold day that a gas utility selects and utilizes for capacity planning purposes. The design day used by Chesapeake for capacity planning purposes is a day with an average temperature of 5˚F. It is also common for gas utilities to reserve pipeline capacity to meet the design day demands of firm transportation customers, or the balancing requirements of its firm transportation customers. If pipeline capacity is reserved on behalf of firm transportation customers, mechanisms are typically in place to recover the costs associated with this capacity from firm transportation customers.

Q. DOES CHESAPEAKE CURRENTLY RESERVE PIPELINE CAPACITY TO MEET THE REQUIREMENTS OF FIRM TRANSPORTATION CUSTOMERS?

A. Yes. Chesapeake currently reserves ESNG and upstream pipeline capacity in amounts sufficient to meet the design day demands of its firm retail sales and firm transportation customers. Firm transportation customers use and pay for the ESNG pipeline capacity reserved on their behalf through an assignment of that capacity. Upstream pipeline capacity is not assigned to or used by firm transportation customers. The upstream capacity reserved by Chesapeake to meet the design day demands of firm transportation customer is excess to the needs of firm sales customers. Until recently, there were no procedures in place to recover from firm transportation customers any of the costs associated with the upstream design day capacity that is excess to the needs of firm sales customers. In Docket No. 13-383, procedures were put in place to recover a portion of these excess upstream pipeline costs from firm transportation customers.

Q. PLEASE DESCRIBE THE HISTORY OF DOCKET NO. 13-383 AND THE PROCEDURES RECENTLY ADOPTED TO RECOVER FROM FIRM TRANSPORTATION CUSTOMERS A PORTION OF THE

COSTS ASSOCIATED WITH THE EXCESS UPSTREAM DESIGN DAY CAPACITY RESERVED BY CHESAPEAKE.

A. In its 2012 GSR proceeding, Docket No. 12-450F, I found that Chesapeake reserved capacity on interstate pipelines upstream of ESNG sufficient to meet the design day requirements of its firm sales and firm transportation customers, but did not require firm transportation customers to pay for the upstream design day capacity reserved on their behalf. The costs associated with reserving upstream capacity on behalf of firm transportation customers were largely paid for by firm sales customers, and I found this to be unreasonable.

Chesapeake's 2012 GSR proceeding was resolved through a settlement agreement which was subsequently approved by the Commission. The settlement agreement approved in Chesapeake's 2012 GSR proceeding required the Company to submit a filing on or before October 1, 2013, proposing an alternative approach to the allocation of upstream pipeline capacity costs.

In its October 1, 2013 filing which was docketed at Docket No. 13-383 (Initial Filing), the Company proposed that firm transportation customers be required to take an assignment of upstream capacity from the Company. In response to concerns expressed by several parties to its Initial Application, the Company filed an Amended Application on September 4, 2014.

In the Amended Application, the Company proposed, among other things, to release the interstate capacity reserved to meet the requirements of firm transportation customers that was excess to the needs of GSR customers into the open market and credit 90 percent of the revenues received from the release of that excess capacity to GSR customers. The remaining 10 percent of the revenues received from the release of the excess capacity would be retained by the Company. Under this approach, GSR customers would be fully responsible for any difference between the costs associated with the excess capacity and the capacity release revenue credited to GSR customers. Staff and DPA did not disagree with the proposal presented in the Amended Application for a number of reasons. A settlement was eventually agreed to between the Company, Staff, and the DPA, and the Settlement was approved by the Commission.[1]

Q. HOW WERE THE COSTS ASSOCIATED WITH THE EXCESS INTERSTATE PIPELINE CAPACITY TO BE RECOVERED UNDER THE SETTLEMENT APPROVED BY THE COMMISSION?

A. The settlement in Docket No. 13-383 provided that the Company would release excess capacity into the open market and that the Company would retain 10 percent of the revenues received from the release of the excess capacity. Determination of the quantity of excess capacity is set forth in Item 12 of the settlement. The difference between the costs associated with the excess capacity and the revenues received from the release of the excess capacity plus the Company's 10 percent share of release revenues would be allocated to the Company's firm sales and transportation customers based on design day demands.[2] Included in the settlement as Exhibit A was an example of the allocation process just described. Attached to my testimony as Schedule JDM-1 is a copy of Exhibit A to the settlement in Docket No. 13-383.

Q. HAS THE COMPANY PROPERLY FOLLOWED THE ALLOCATION PROCESS FOR THE RECOVERY OF EXCESS CAPACITY COSTS

[1] *See* Order No. 8752. The United States Air Force ("USAF") was a party in this docket, but it did not sign the settlement, however, it advised the Commission that it did not oppose the settlement. *See id.*, Hearing Examiner's Report at p. 11, n.8.

[2] The costs associated with the excess capacity are determined based on Chesapeake's weighted average cost of upstream pipeline capacity.

AS PRESENTED IN EXHIBIT A OF THE SETTLEMENT IN DOCKET NO. 13-383?

A. No. Exhibit 1 (Confidential) to the testimony of Chesapeake witness Sarah E. Hardy presents the Company's proposed allocation of excess capacity costs pursuant to the settlement in Docket No. 13-383 based on an estimate of the capacity release revenues to be received from the release of that capacity. An estimate was used because at the time the Company filed its application in this proceeding the release of excess upstream pipeline capacity had not yet occurred. As shown in Exhibit 1, the Company is proposing to allocate the difference between the actual costs associated with the excess capacity and the revenues realized from the release of that capacity from firm sales and transportation customers based on design day demands. However, the settlement in Docket No. 13-383 also required the Company's 10 percent share of capacity release revenues to be included in the amount allocated to firm sales and transportation customers. The Company has failed to include its 10 percent share in the costs it is proposing to allocate to firm sales and transportation customers. The Company's proposal should be revised accordingly.

Q. HAVE YOU REVISED THE COMPANY'S EXHIBIT 1 TO PROPERLY REFLECT THE PROCEDURES REQUIRED UNDER THE SETTLEMENT IN DOCKET NO. 13-383?

A. Yes. Schedule JDM-2 (Confidential) presents a revised Company Exhibit 1 to reflect the requirements of the settlement in Docket No. 13-383. Schedule JDM-2 has also been updated to reflect the actual rather than estimated revenues to be realized from the release of excess capacity. As shown in Schedule JDM-2, the additional amount to be credited to firm sales customers is $188,867. I recommend that this amount be reflected in the under- and over-collection balance.

V. ASSET MANAGEMENT ARRANGEMENT

Q. DOES CHESAPEAKE OPERATE UNDER AN ASSET MANAGEMENT AGREEMENT (AMA)?

A. Yes. Chesapeake operates under an AMA which became effective April 1, 2013.

Q. BRIEFLY DESCRIBE THE AMA UNDER WHICH CHESAPEAKE OPERATES.

A. Under the AMA, Chesapeake's upstream interstate pipeline capacity has been assigned to a third-party service provider, or Asset Manager.[3] The Asset Manager provides Chesapeake with capacity management, supply and dispatch scheduling on pipelines upstream of ESNG, firm and interruptible gas supply, balancing of supply resources, and monthly accounting and reporting of transactions. Chesapeake receives a fee from the Asset Manager which is credited 92.5 percent to GSR customers and 7.5 percent is retained by the Company pursuant to the Settlement Agreement approved in Docket No. 12-450F.

Q. HOW WAS THE ASSET MANAGER SELECTED?

A. The Asset Manager was selected through an RFP process.

Q. WHAT IS THE TERM OF THE AMA?

A. The initial term of the AMA was April 1, 2013 through March 31, 2015. The Company and the Asset Manager recently negotiated a two-year extension of the initial term with the AMA now expiring March 31, 2017. The AMA fee currently received by the Company is $2.3 million.

Q. HOW IS THE PRICE PAID FOR THE GAS SUPPLIES PURCHASED BY CHESAPEAKE UNDER THE AMA DETERMINED?

[3] The capacity released on the open market pursuant to the settlement in Docket No. 13-383 is not assigned.

A. As noted previously, Chesapeake reserves capacity on three upstream interstate pipelines. The price of gas available for purchase on each pipeline can vary significantly. The AMA contains several formulas that identify how the price of the gas sold to Chesapeake will be determined. Generally, the price paid by Chesapeake reflects market prices for each pipeline weighted by the amount of capacity Chesapeake reserves on each pipeline.

Q. HOW CAN THE REASONABLENESS OF THE CURRENT AMA FEE BE EVALUATED?

A. The Asset Manager can release the capacity assigned to it by Chesapeake to others and generate revenues, and use the assigned capacity to make off-system sales and generate revenues. These capacity release and off-system sales revenues are retained by the Asset Manager. The Asset Manager can also generate revenue by selling gas to Chesapeake at prices in excess of the cost paid by the Asset Manager to purchase that gas. This can occur because the formula price for gas purchased under the AMA can exceed the Asset Manager's actual cost of gas.

If Chesapeake did not operate under an AMA, the Company would utilize the capacity that would have been assigned to the Asset Manager to generate revenue from capacity release and off-system sales activities. Without the AMA, these revenues would be credited to GSR customers. If Chesapeake were able to buy gas at prices that were less than the AMA formula determined prices, the benefit of these lower cost purchases would also accrue to GSR customers. The reasonableness of the current AMA fee can be evaluated by comparing the fee to an estimate of the revenues which could be expected to be realized by GSR customers if the Company did not release its capacity to an Asset Manager. This would include revenues from capacity release and off-system sales activities, plus any reduction in the price paid for gas. If the AMA fee exceeds the estimated benefit to GSR customers of the Company maintaining its upstream pipeline capacity, the AMA fee can be considered reasonable.

Q. DOES THE COMPANY CURRENTLY REGULARLY EVALUATE WHETHER THE AMA FEE IS REASONABLE?

A. As indicated by the response to Staff/DPA data request No. 64 attached to my testimony as Schedule JDM-3, the Company does not evaluate the reasonableness of the AMA fee. I recommend that the Company be required to regularly evaluate the reasonableness of its AMA fees to ensure GSR customers received the maximum benefit from the utilization of upstream pipeline capacity.

Q. DID THE SETTLEMENT IN CHESAPEAKE'S 2014 GSR PROCEEDING ADDRESS THE SELECTION OF FUTURE ASSET MANAGERS?

A. Yes. The Settlement in Docket No. 14-0299 required Chesapeake to issue an RFP for all future AMAs.

Q. IS THE COMPANY PROPOSING AN ALTERNATIVE TO ISSUING AN RFP FOR THE CURRENT AMA THAT EXPIRES MARCH 17, 2017?

A. Yes. Also in the response to Staff/DPA No. 64, the Company indicated:

> The Company recommends that the parties open a discussion regarding the utilization of the Company's affiliate, Peninsula Energy Services Company, Inc. ("PESCO"), to manage its gas supply related assets after the current AMA expires. Utilization of an affiliate for asset management is common in the industry and the parties could develop an open and transparent sharing mechanism that would enable the GSR customers to benefit in real time from evolving market dynamics that favor the Company's asset mix.

Q. SHOULD STAFF/DPA OPPOSE OPENING A DISCUSSION WITH CHESAPEAKE REGARDING THE USE OF PESCO AS AN ASSET MANAGER AFTER EXPIRATION OF THE CURRENT AMA?

A. No. However, any consideration of the Company's proposal will require that the Company regularly evaluate the reasonableness of its current AMA fee as I have recommended.

Q. ARE THERE OTHER ISSUES WHICH YOU BELIEVE STAFF/DPA SHOULD CONSIDER?

A. Yes. As explained in the next section of my testimony, Staff/DPA should discuss with the Company the rates filed by Chesapeake in future GSR filings prior to the actual filing of its annual application.

VI. <u>ANNUAL GSR RATES</u>

Q. WHAT ISSUES SHOULD STAFF/DPA DISCUSS PRIOR TO THE COMPANY'S FILING OF ITS ANNUAL GSR APPLICATION?

A. In its filing, Chesapeake has proposed decreasing the GSR of a typical firm sales customers from $10.69 per Mcf to $6.81 per Mcf, or by 36 percent. One portion of this decline, or $0.71 per Mcf, is due to the elimination of an under-collection reflected in the Company's prior GSR filing. Another portion of this decline, $1.40 per Mcf, is the return of the current over-collection. All else being equal, the GSR of most customers will increase by $1.40 per Mcf, or 21 percent, in the Company's next annual GSR filing. The Company operates a hedging program to mitigate the volatility of its GSR, but the mitigating impact of its hedging program is being offset by its under- and over-collection balances. I recommend that the parties hold quarterly discussions to review the Company's hedging program, under- and over-collection balances, and other areas of interest. This would include determining whether measures should be implemented in the Company's annual GSR application to mitigate changes in rates that would be caused by the amortization of under- and over-collection balances. Delmarva Power and Light Company currently holds quarterly discussions to address such matters with Staff and the DPA.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF CHESAPEAKE UTILITIES CORPORATION FOR APPROVAL OF A CHANGE IN ITS GAS SALES SERVICE RATES ("GSR") TO BE EFFECTIVE NOVEMBER 1, 2015 (FILED SEPTEMBER 1, 2015)	**)))))))**	**PSC DOCKET NO. 15-1362**

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY OF

JEROME D. MIERZWA

ON BEHALF OF THE

STAFF OF THE DELAWARE PUBLIC SERVICE COMMISSION AND DIVISION OF THE PUBLIC ADVOCATE

January 27, 2016

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

Exhibit A to Settlement in Docket # 13-383

Excess Capacity:		14,267
Average Annual Cost:	$	166.31
Cost of Excess Capacity	$	2,372,745
Released at 50% of cost:	$	1,186,372
Company 10% share:		118,637
Amount to Recover	$	1,305,010

Billing Units (Mcf)	Design Demand	Percent
Sales	51,660	68%
Transportation	23,925	32%
Total	75,585	100%

Allocation based on Design Day Demand

Costs:	$	1,305,010
Billing Units:		75,585
Per Unit Charge:	$	17.2655
Sales Allocation:	$	891,934
Transportation Allocation:	$	413,076
Total Recovery	$	1,305,010

~CONFIDENTIAL~

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CHESAPEAKE UTILITY CORPORATION
Allocation of Excess Upstream Capacity Costs

Excess Capacity		12,646	
Average Cost		$167.09	
Cost of Excess		$2,113,028	
Release revenue		[redacted]	
Company 10%		[redacted]	
Credit to Sales		[redacted]	[redacted]
Additional to Recover		[redacted]	
Units	Sales	[redacted]	[redacted]
	Transport	[redacted]	[redacted]
	Total	[redacted]	[redacted]
Allocation	Sales	[redacted]	
	Transport	[redacted]	[redacted]
	Total	[redacted]	
Total Sales Customer Credit (a plus b)			
Per Staff/DPA		[redacted]	
Per Company		[redacted]	
Staff/DPA Adjustment		$188,867	

Chesapeake Utilities Corporation
Delaware Division
The Delaware Public Service Commission Staff &
The Delaware Public Advocate's Data Requests
Gas Sales Service Rate
PSC Docket No. 15-1362
January 8, 2016

Question PSC-DPA-64

Has the Company performed any analyses of what its monthly commodity cost of gas would be without the AMA compared to what the costs are under the AMA? If yes, please provide a copy of those analyses covering the period November 2014 – October 2015. If no, why haven't such analyses been performed?

Response:

The Company has not performed such an analysis.

The Company views its AMA in the broad context of overall supply and capacity management which incorporates many considerations. The cost of the gas commodity is one component of the AMA but it has been our experience that any effort to quantify the individual components of a comprehensive management service will not generate meaningful data. Overall the provisions of the AMA that the Company negotiated provide us with a mechanism to fully utilize the assets that we hold in order to balance regional risks in the determination of our commodity pricing. Moreover we use our Risk Management Plan to hedge a percentage of our gas supply requirements to address commodity price volatility risks.

The Company believes that the proliferation of shale gas production in the Marcellus and Utica areas has changed the traditional fundamentals of the natural gas market; however, the market is still evolving. There are currently a number of infrastructure projects underway that will facilitate backhauling the Marcellus shale gas to various southeast states, including Virginia, North Carolina, South Carolina and Georgia. These projects should facilitate competition between Henry Hub producers and marketers, with equally positioned Marcellus participants. Once it can be reasonably determined that the natural gas market has sufficiently progressed in a way that balances the multiple producing areas, a reevaluation of commodity pricing methodologies in conjunction with a similar reassessment of the Company's total gas supply asset portfolio would be appropriate.

In this vein, the Company recommends that the parties open a discussion regarding the utilization of the Company's affiliate, Peninsula Energy Services Company, Inc. (PESCO), to manage its gas supply related assets after the current AMA expires. Utilization of an affiliate for asset management is common in the industry and the parties could develop an open and transparent sharing mechanism that would enable the GSR customers to benefit in real time from evolving market dynamics that favor the Company's asset mix.